Section 6: Natural Gas Prices, Volatility, and Forecasts

Components of Natural Gas Price

An array of different natural gas prices are encountered in the media. Care must be taken when comparing gas price histories or forecasts that the same category of natural gas is being compared. The most common categories of gas prices are:

- Wellhead price - what the producer can get in the producing areas. This price varies by region, and is often expressed as a weighted U.S. or Canadian average.
- Beginning of interstate pipeline price - slightly higher than wellhead price as it includes costs for gathering and conditioning of the natural gas. Typical cost addition relative to wellhead price of $0.15/MMBtu.
- End of interstate pipeline price - includes a transportation charge. Typical cost addition for transportation of $0.45/MMBtu.
- Trading hub spot price - Henry Hub in Louisiana is the most frequently cited. The closest regional hub is at Sumas, Washington. Hub price is dependent on market conditions.
- City gate price – usually located in large metropolitan areas such as Chicago, New York or Los Angeles. City gate price is dependent on market conditions.
- Customer prices - include utility distribution costs and vary between residential, commercial, power generation and industrial sectors. Typical delivery cost addition of $0.25/MMBtu for electricity generators, $0.45/MMBtu for industrial customers and $2.5/MMBtu for commercial and residential customers.

The natural gas prices most frequently used in forecasting reports are wellhead and trading hub prices. The differences in the costs shown above primarily represent the value of transportation and gas services. The recent higher wellhead and trading hub gas prices are often referenced to historical prices of the 1990s and are expressed as a percent increase. Note that a 100 percent increase in wellhead price (i.e. from $2.5 to $5.0/MMBtu) does not translate into an equivalent percentage increase for consumers due to the fixed transportation component of the final delivered product. A 100 percent wellhead price increase might translate into an 80 percent price increase for electricity generators and a 40 percent increase for residential consumers. The California Energy Commission estimated the price differentials presented above in 2003.

Recent Price Volatility in the Natural Gas Market: 2000 – 2003

For much of the 1990s wellhead and trading hub natural gas prices remained around the $2/MMBtu range, though there was evidence that prices were moving up towards the end of the decade. By mid 2000 prices had moved past $3/MMBtu as the result of increased demand following several years of sustained economic growth, which had reduced spare natural gas productive capacity. In the winter of 2000-01 two additional factors combined to sharply increase natural gas prices. On the West Coast a crisis in the electricity market had emerged, triggered in part by energy deregulation and market manipulation in California, and worsened by a drought that reduced hydroelectric generating capacity. To make up for the reduced hydroelectric power on the West Coast, thermal generation units, primarily gas fired, were called on to run more frequently resulting in increased gas consumption. The second factor was a colder than normal winter in the rest of the nation that followed on a series of mild winters, leading to additional residential and commercial demand for natural gas.

After two or three months of higher prices, natural gas drilling activity began to increase and soon thereafter gas production also began to rise. More importantly, mild weather, fuel switching, and a rapidly deteriorating economy resulted in reduced demand for natural gas. Prices fell back to early 1990s levels of $2 to $3/MMBtu and storage inventories were rapidly rebuilt achieving a five-year high by October of 2002. Some observers believed that increased supply, the result of higher gas prices and more drilling, had driven prices back to their traditional range. This optimistic view conveniently overlooked the significant reduction on the demand side, the result of a mild winter (2001-02), industrial fuel switching, and the recession that began in late 2000. Between April 1, 2001, and March 31, 2002, U.S. natural gas demand declined by roughly 2 Tcf (9 percent) relative to consumption in the prior 12 months (Weismann, 2003).

During the middle of 2002, oil prices began to rise as oil worker strikes in Venezuela, and tensions in the Middle East began to escalate. Low gas prices and higher prices for petroleum fuels caused some industrial users that switched fuels in 2001 to switch back to natural gas, boosting natural gas consumption and putting some upward pressure on gas prices. A slightly colder than normal winter heating season during 2002-03 in much of the country and a modest economic recovery resulted in a slight up tick in demand for natural gas. More importantly the brief return to low gas prices resulted in a drastic reduction in exploration and drilling in the United States and Canada. Because of the rapid production decline rates exhibited by new gas wells and the continued declines in the wells located on older large gas fields, production slipped noticeably during late 2002 and early 2003.[1] Despite entering the 2002-03 winter heating season with natural gas storage inventories at the high end of normal (3,185 Bcf), production and inventory draw downs were *nearly insufficient* to carry the nation, particularly the East Coast, through a winter that had only 3 percent more heating degree days than the composite 30 year average.[2] In fact the winter of 2002-03 produced the largest gas storage draw down ever recorded: 2,530 Bcf over the course of the heating season. Just as the rapid rise in gas storage inventories heralded the natural gas price collapse of late 2001, the rapid draw down of inventories starting in late 2002 and continuing through April 2003 was a signal to the market that natural gas was once again in short supply and prices rose accordingly.

The pattern of weekly storage levels for the Lower 48 region, West, East and producing sub regions is shown in Figure 6.1. The winter of 2000-01 resulted in low gas storage levels (beginning from a low peak storage in November of 2000), and was more severe on the West Coast because of the drought and California energy crisis. The winter of 2002-03 gas storage draw down was particularly severe for the East Coast and the

---

[1] U.S. dry gas production declined from 19.6 Tcf in 2001, to 19.0 Tcf in 2002 (EIA, *Short-term Energy Outlook*, 2003).

[2] At the end of the winter heating season gas inventories were drawn down to 642 Bcf, the lowest level in the 10 years since the EIA began tracking storage (EIA historical storage data).

producing regions. On the West Coast and in the Pacific Northwest, the winter of 2002-03 was mild and consequently gas storage remained sufficient. However, over the last decade or two, natural gas has to a large degree become a national commodity that can be readily exchanged between consuming sub regions. Thus a significant gas shortage and consequent high prices in one part of the country can induce higher prices in other parts of the country.

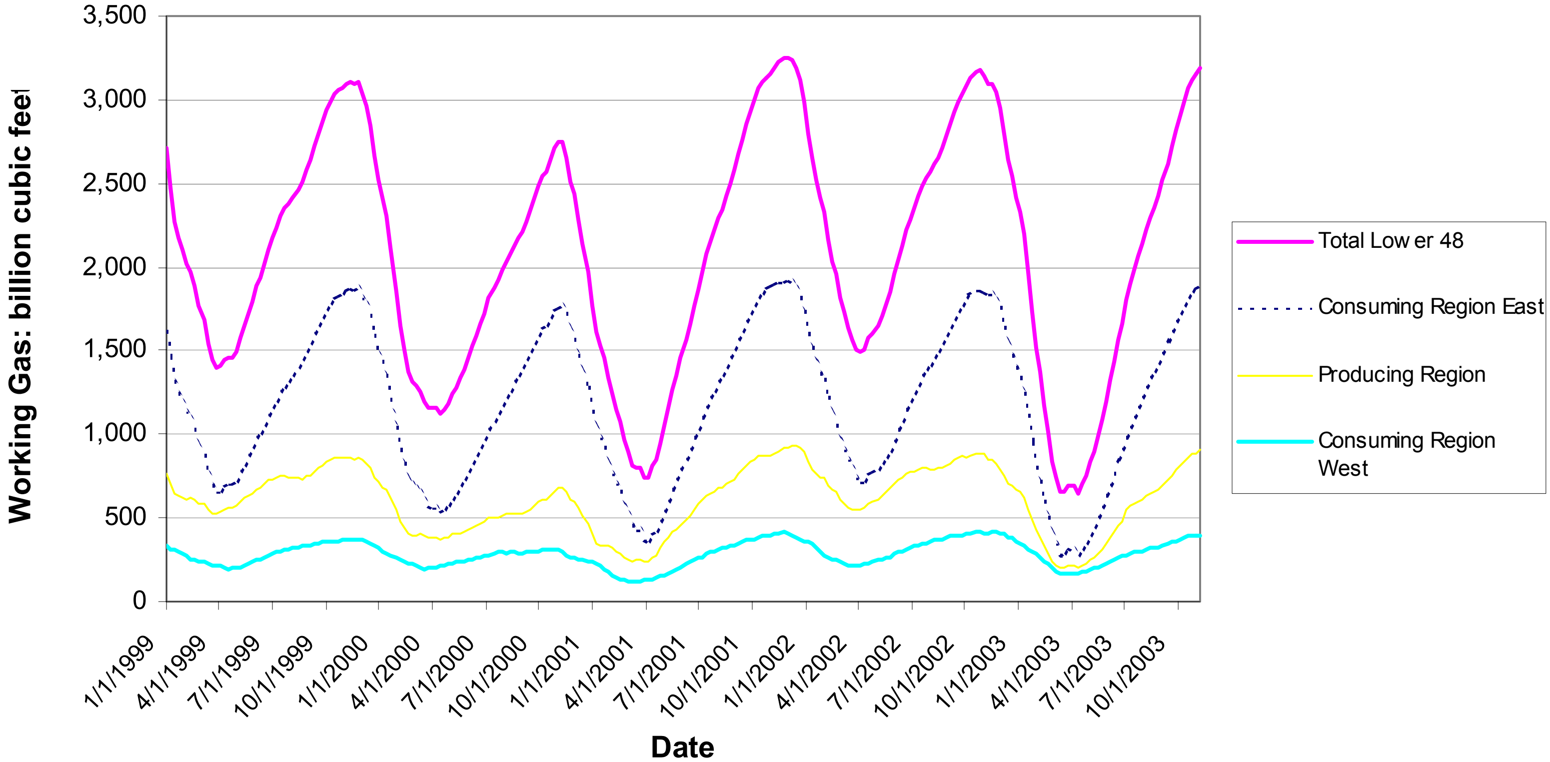

Figure 6.1: Weekly U.S. Natural Gas Storage: 1999-2003
Source: EIA

Supply Limitations – Primary Cause of Recent Natural Gas Price Volatility

While there were similarities between the conditions that lead to the 2000-01 and 2003 natural gas price spikes (slightly colder winters, increasing reliance on gas-fired electrical generation), there was also a significant difference. In late 2002 and early 2003, the U.S. economy was close to being in a recession, while in 2000 the economy, though slowing, was still quite robust. Despite the fact that industrial demand was significantly reduced in late 2002 relative to 2000, a second run up in gas price occurred. The underlying cause of the second gas price spike was lagging North American gas production.

The initial natural gas price spike in 2000-01 was the first overt sign that the North American gas market had entered a period of supply limitations and consequently a period of higher prices and price volatility. Because of a drought on the West Coast, manipulation in the energy markets by Enron and other marketers, and a cold winter for the eastern part of the nation, it was easy to ignore the warning implicit in the initial gas price spike. While a poorly designed electricity market in California and insufficient federal oversight of energy markets in general may have contributed to the 2000-2001 increase in gas prices, the underlying cause was primarily rooted in a gas market where supply was unable to meet demand. The second price spike during the slightly colder than average winter of 2002-03, occurred despite a period of reduced economic activity and convinced most observers that gas supply constraints for the North American market would remain for at least the next five years, and possibly longer. During this period, gas prices will be highly dependent on the severity of the weather, particularly during the winter, the level of economic activity, and whether industrial gas demand continues to decline due to fuel switching, efficiency gains and demand destruction (businesses failing or relocating). Continued rapid growth in gas-fired electrical generation capacity also has the potential to significantly impact mid-term and long-term natural gas prices.

Key Drivers of Natural Gas Price and Volatility

In a natural gas market where supply and demand are in tight balance several factors can influence price and volatility. These factors are discussed below.

Weather

Weather can have a significant impact on daily and monthly natural gas consumption and consequently short-term natural gas prices. During the coldest months of winter average consumption exceeds 80 Bcf /day.[3] Summer gas consumption averages only about 45 Bcf/day, while average supply (U.S. production and imports) is about 62-64 Bcf/day. A colder winter, such as that of 2000-01, can significantly increase daily demand and cause prices to jump dramatically on the daily and month ahead spot markets. Hot summer days increase air-conditioning and electricity demand, which in turn increases demand for natural gas-fired electricity generation. Currently, high summer gas demand does not tax the U.S. gas supply and infrastructure systems to the same degree that increased winter demand does.[4]

Drought and/or Reduced Snow Pack

Hydroelectric generation is the source of much of the electricity used in the Western United States and Canada. The Pacific Northwest is particularly dependent on hydroelectricity. Drought years, such as 2001, result in substantial reductions in hydroelectricity capacity.[5] Natural gas-fired generating units make up the shortfall in hydroelectricity, which puts upward pressure on natural gas prices for all users.

The mountain snow pack acts as a giant reservoir for the Pacific Northwest hydroelectricity system. Low snow pack can occur in non-drought years, reducing the amount of hydroelectric generating capacity, and necessitating additional generation from thermal resources including natural gas-fired generating units. Over the long-term,

---

[3] Extremely cold days can bring daily consumption to over 100 Bcf.

[4] However, high summer gas demand can result in significant reductions in storage injections for winter use, which will lead to increases in gas price and volatility.

[5] Hydroelectric production on the Federal Power System in 2001 was 45 percent less than production in 1997 and 40 percent less than 1999 (4,000-5,000 aMW deficit).

global warming is expected to reduce mountain snow pack and strain the hydroelectricity generating system on the West Coast.

Natural Gas Storage Levels

For about four months of the year (typically December through March) natural gas U.S. consumption exceeds the amount available from production and imports. During this period, natural gas storage is used to make up the supply deficit. Using gas storage as part of the supply system moderates prices and minimizes interruptions to consumers. Because on a national level, natural gas is a freely traded commodity, buyers and sellers closely watch not only the amount of gas in storage, but also the rate at which gas is added or withdrawn from storage. Abnormally high or low storages levels, or high or low injection or withdrawal rates of gas, can signal future supply-demand imbalance thereby influencing spot and forward market prices. High storage levels during the winter of 2001-02 in part caused low short-term gas prices, while low storage levels during the spring of 2003 in part caused high short-term gas prices.

Oil Prices

Historically, many industrial and utility customers have had the ability to switch between natural gas and petroleum fuels depending on prices. Higher oil prices in the early 1980s were in part responsible for the elevated gas prices seen during this period. During the late 1980s and 1990s low oil prices may have reduced natural gas prices and volatility. During the recent price spike of 2002-03 it became evident that gas prices had to some degree become decoupled from petroleum prices.[6] Two factors have allowed natural gas and oil prices to decouple: First because of more stringent air quality regulations there is now very limited fuel switching capability in the U.S. economy; second, natural gas supplies in North America are constrained and cannot be supplemented by imports.

Inelasticity of Natural Gas Supply and Demand

The current North American gas market has little excess production capacity (see Figure 3.6), which means short-term increases in natural gas demand are very inelastic.[7] In other words it is very difficult to bring new supply on line to replace lost production, or to meet increases in demand and/or price. Short-term supply inelasticity has contributed to the natural gas price volatility of the last several years. Over the long-term (two to 10 years), supply is generally more elastic as new supplies (unconventional gas, Arctic supplies, LNG, etc) can be developed. These new sources of natural gas can serve to dampen price volatility.

Short-term natural gas demand is also relatively inelastic. In the residential, commercial, and the electrical generation sector short-term natural gas demand is relatively inelastic; That is consumption does not change markedly as price increases or decreases.[8] Over the

[6] An old rule of thumb was that Henry Hub natural gas should be priced at just over \$1/Mcf for each \$10 of West Texas Intermediate price. Current oil prices would allow natural gas at about \$3.5/MMBtu, roughly 40 percent lower than actually observed.

[7] Price elasticity = percent use reduction (increase) / percent price increase (reduction)

[8] Residential and commercial consumers are insulated from short-term changes in gas price by regulatory processes, and consequently do not change consumption when spot market prices increase.

long-term, natural gas demand is more elastic and will respond to sustained high prices. The National Energy Modeling System used by the U.S. Department of Energy and others uses short-term price elasticities of -0.24 to -0.28 and long-term values of –0.33 to -0.51.[9] Following a sustained gas price increase, demand will be gradually reduced as a result of efficiency upgrades, which take the form of new appliances or equipment, and conservation, which generally refers to behavioral changes such as reduced use of heating, cooling and lighting.

The industrial sector differs from the three sectors mentioned above in that its short-term natural gas demand is slightly more responsive (more elastic) to price increases. Industrial price-demand responsiveness takes two forms. The first comprises efficiency and conservation efforts, such as upgrading equipment or shifting production to more energy efficient equipment and some behavioral changes. The second form of natural gas demand reduction includes temporary fuel switching that some industrial operations are capable of on relatively short notice. During the natural gas price spikes of 2001 and 2003 a significant number of industrial gas consumers switched to distillate or residual oil.[10]

Pipeline Capacity

Although the North American pipeline network is extensive and provides sufficient capacity for most demand requirements, there are locations that can become constrained during periods of peak winter demand. These constraints show up as larger than normal price differentials between the main hubs in producing regions and city gate hubs in the consuming regions. Price differentials reflect the value of transporting gas between regions and provide incentives for new pipeline capacity additions as well as new supply additions. Periodically there has been a significant price differential between the Opal, Wyoming, gas hub in the producing region of the Rockies and the distribution hubs of Blanco, New Mexico, and Malin, Oregon: Two important gas hubs that service the California market. These price differentials were in part caused by pipeline capacity limitations during peak demand periods.

Lack of Reliable Information

The EIA publishes weekly and monthly information on natural gas supply, demand and storage. However, much of the information is lagged by six or more months, and is based partially on estimates out to 18 months. In addition the EIA frequently revises its most recently released information. The information time lag and revisions cause uncertainty for both producers and consumers alike, and contribute to price volatility. An example of this problem occurred during the recent gas spike in the spring of 2003, when the EIA frequently revised estimates of weekly storage withdrawals. Another government entity, the National Oceanographic and Atmospheric Administration (NOAA), also contributed to the information uncertainty when it initially reported that the winter of 2002-03, during which gas storage was drawn down dramatically, was slightly warmer than average. This information may have caused gas marketers to over

---

[9] A larger negative number indicates more price elasticity of demand: A value of –1.0 indicates that a 10 percent price increase results in a 10 percent reduction in demand.

[10] High petroleum prices in 2004 have probably stopped and may have reversed some of the fuel switching.

estimate the supply shortfall. NOAA subsequently reevaluated its data and portrayed the winter as slightly colder than average.[11]

Factors that Mitigate Price Volatility

A number of factors can work, alone or in combination, to reduce natural gas price volatility. These factors are briefly discussed below.

Sufficient Gas Storage

Gas storage is used routinely to smooth out supply and demand imbalances, particularly during the winter heating season. As noted above, excess gas in storage during and after the winter of 2001-02 caused prices to decline and remain relatively low and stable for the following six months. Regulators, suppliers and the Federal Energy Regulatory Commission (FERC) can work to ensure that sufficient gas storage is available and strategically located.

Fuel Switching

Fuel switching, or fuel substitution, is a means by which businesses that use large amounts of fossil fuel can mitigate high costs for a particular fuel. Fuel switching is not only a valuable option for industrial gas consumers, but for society as a whole since removing even a small fraction of industrial gas use can result in a noticeable price drop that also benefits commercial and residential gas consumers as well. Fuel switching capability essentially makes demand response to price more elastic in nature.

Fuel switching is primarily limited to older gas-fired power plants and boilers. Newer gas-fired power plants and boilers are designed to run almost exclusively on natural gas.[12] Analysts estimate the fuel switching potential at 2 Bcf/day (Michot-Foss, 2003). Though small, a reduction in consumption of 2 Bcf/day (equivalent to a few percent) can have a marked impact on short-term prices in a tight market. Figure 6.2 below illustrates the price points at which plant shutdowns or fuel switching occur, and the estimated volume of daily gas usage that is avoided. Price point estimates were made based on $20/barrel oil: Higher oil prices, as observed in early 2003 and 2004, will move the shutdown or fuel switching price points outward (to the right).

---

[11] An initial evaluation of the winter of 2002-03 indicated 2 percent fewer Heating Degree Days (HDD) than an average winter, while the re-evaluation put the number of HDD at 3 percent more than normal.

[12] Newer power plants and boilers have air pollutant emission constraints that prevent them from converting their equipment to run on distillate fuel.

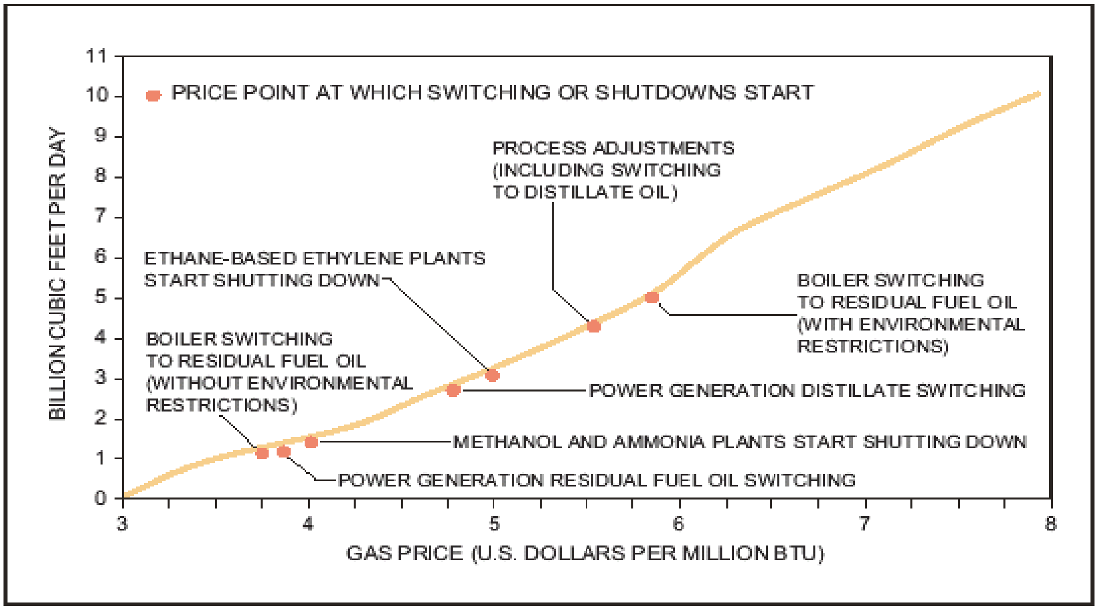

Figure 6.2: Industrial and power generation natural gas flexibility
Source: NPC, 2003.

In the past, the ability to fuel switch between natural gas and distillate or residual oil insulated the nation from petroleum or natural gas supply shocks. As petroleum derived fuels have been displaced by natural gas from use in the residential, commercial and particularly the industrial sector we have lost much of the flexibility of fuel switching.

Excess Production Capacity or Supply

The current natural gas market is supply constrained, with very little excess production capacity. Excess production capacity, which was available from 1985 until 1997, allows supply to respond quickly to modest increases in demand or price. Developing excess production or supply would moderate price volatility.[13] In the long-term, ten or more years, LNG will serve as the excess supply for the U.S. gas market. To effectively utilize excess production capacity there must also be sufficient pipeline capacity.

Long-term Contracting and Financial Hedging

Following market deregulation there has been a gradual transition from long-term to short-term contracts. This worked out well for industrial and Local Distribution Companies (LDCs) during the 1990s when short-term market prices were low and relatively stable. Recent market volatility seems to be providing an incentive to engage in longer-term contracts once again. Unfortunately many LDCs and industries are not financially sound enough to develop favorable long-term contracts.

Residential and most commercial gas consumers are served by LDCs at regulated rates, which are adjusted on a forward basis periodically to account for changes in market price. The current high and volatile prices have caused many LDCs to seek physical or financial

[13] Natural gas supply would become more elastic with respect to price.

hedging opportunities. Industrial customers are also using gas price hedging techniques more frequently.

Timely and Reliable Information

As discussed above time lagged and inaccurate information can lead to volatility in the natural gas market. The EIA, FERC and private companies that monitor the natural gas markets are taking steps to improve the information that is available. The FERC has recently investigated and penalized several marketing firms that misrepresented natural gas sales during the California energy crisis.

Conservation and Efficiency

Industrial, commercial and residential users will respond to high natural prices by pursuing short-term conservation and efficiency improvements. In the commercial and industrial sectors efficiency measures would include replacement or upgrading of older natural gas equipment (heaters, boilers, etc.), while in the residential sector efficiency measures would consist of switching to more energy efficient heaters and appliances. It is estimated that short-term efficiency measures can reduce natural gas consumption by 0.3 to 0.5 Bcf/day (Michot-Foss, 2003).

Conservation measures are more behavioral in nature and result primarily in temporary reductions in natural gas usage. Conservation efforts would occur in all sectors and include reducing heating demand in the winter by lowering thermostat settings, and reducing electricity used to meet air conditioning requirements in the summer. Short-term conservation efforts have the potential to reduce natural gas consumption by 0.5 to 1.5 Bcf/day, or 0.8 to 2.4 percent (Michot-Foss, 2003).

Reductions in Natural Gas Price and Volatility by Demand Destruction

Although demand destruction is not a desired outcome it does serve to reduce both upward pressure on gas price and volatility. Demand destruction typically refers to the temporary or permanent shuttering of operations in the most energy intensive industries, and often involves the relocation of the industrial operation to another country where energy (natural gas, electricity, etc.) is significantly less expensive. Usually there are multiple factors (labor costs, market access, regulations, etc.) that cause a business to relocate an industrial operation, making it difficult to assess the level of demand destruction that is solely the result of higher energy prices. Figure 6.2 above illustrates the price points at which some energy intensive industries shut down or switch fuel and the associated amounts of natural gas involved with these actions.

The fertilizer industry synthesizes ammonia and urea, which are frequently combined with other key ingredients to make fertilizer. Natural gas can account for 90 percent of the cost of producing ammonia; so high natural gas prices directly impact the price of fertilizer, and the competitiveness of the U.S. industry. Recent high natural gas prices have caused 20 percent of fertilizer plants to permanently shut down and another 25 percent to idle their production (Knight Ridder, 2003).[14]

---

[14] Demand destruction during 2000-03 in the fertilizer industry represents slightly more than 0.6 Bcf/day or 1 percent of U.S. natural gas consumption.

The chemical industry manufactures chemical precursors such as ethylene, propylene and methanol, which are used primarily by the chemical and plastic manufacturing industries to form more complex compounds. In response to high oil prices, much of the American chemical industry switched to natural gas for its feedstock and energy source in the production of these precursor chemicals. Since 2000, the industry has been at a competitive disadvantage because of high North American gas prices. It is unclear how much production has been lost due to high natural gas prices, but anecdotal evidence suggests that several plants have closed and a number of others have curtailed operations.

The Northwest has few fertilizer or chemical businesses and will not be significantly impacted directly. However, farmers and manufacturers that buy or sell products from or to these industries will be impacted by higher gas prices.

Extent of Recent Fuel Switching and Demand Destruction

While it is difficult to directly estimate the reduction in natural gas usage caused by current high prices, there is anecdotal evidence to support claims of at least a 5 percent reduction in gas demand. In recent testimony before the United States House Energy Committee information was presented that indicated a reduction in demand of 3 to 6 Bcf/day, equivalent to roughly 5 to 10 percent of average daily U.S. natural gas consumption, could be anticipated (Michot-Foss, 2003). Energy analysts Andy Weismann of Energy Ventures Group and Ron Denhardt of Strategic Energy & Economic Research, Inc., suggest that following the 2000-01 natural gas price spike, demand was reduced by 6 Bcf/day, with a 2 Bcf/day reduction from fuel switching, and the rest due to mild weather, and the recession of 2001-02.

Economic Consequences of High Natural Gas Prices

Sustained high natural gas prices reduce economic output and growth. The Industrial Energy Consumers of America (IECA) recently sent Congress a report on the financial impact of the "gas crisis" that began in June 2000. The report noted that while gas prices had averaged $2.37/MMBtu in the 41 months prior to June 2000, they had averaged $4.34/MMBtu in the subsequent 41 month period: representing an 83 percent increase. The direct cost to consumers of the higher gas prices over 41 months was calculated at $111 billion.

However, the IECA report didn't take into account the extra earnings that higher gas prices represent for energy exploration and production (E&P) companies: The $111 billion in excess consumer costs are not a true loss to society, but rather a transfer of wealth to energy companies, many of whom are domestic. A large fraction of the transferred wealth ends up as dividends or earnings for shareholders or goes to support increased employment at the E&P companies. On the other hand the IECA report didn't take into account indirect costs due to reductions in savings and investment opportunities for individuals or businesses, or plant shutdowns and relocations. These later effects represent true losses to our society from higher gas prices.

While a considerable amount of work has been done on the overall economic consequences of higher oil prices, little has been done on the effects of higher natural gas prices. However, until recently, oil and natural gas prices were fairly strongly linked and so research on the impacts of higher oil prices can be used as a proxy for studying the effects of higher natural gas prices. Stephen Brown, director of energy economics at the Federal Reserve Bank of Dallas made a rough estimate using information from oil price shock research and stated that a sustained doubling of (wellhead) natural gas prices would reduce U.S. Gross Domestic Product by 0.6 to 2.1 percent and increase inflation by a similar amount. He noted that the economic effects would vary widely across regions and industries: States that produce and export natural gas, such as Wyoming, would gain, while states that import natural gas, such as Washington on average would experience economic loses due to higher gas prices.

Natural Gas Price Forecasts

Near-Term Forecast

During the summer of 2003, gas storage injections continued at a record pace; the 10-week period from June 1 saw nearly 1 Tcf of gas injected into storage compared to a 10-year average for this period of 763 Bcf. By early November 2003 gas storage was at 3,187 Bcf, well above what is considered the safe level for a normal winter heating season. As a consequence of the greater than normal additions to gas storage, spot market prices have declined significantly. June monthly spot market prices that averaged $6/MMBtu, gave way to a November 2003 average of just over $4/MMBtu. Prices in the natural gas futures market also declined appreciably over the summer as gas storage inventories grew, but show signs of remaining high through 2004: New York Mercantile Exchange (NYMEX) futures contracts are shown in Figure 6.3 below. During early 2004, as oil prices have risen, gas futures prices have moved back above $5/MMBtu. The EIA reports that natural gas prices averaged $5.51/MMBtu for 2003, and forecasts that they will remain at around $5/MMBtu in 2004 and 2005 (EIA, 2004). A cold winter or extremely hot summer could cause demand to increase and prices to climb again.

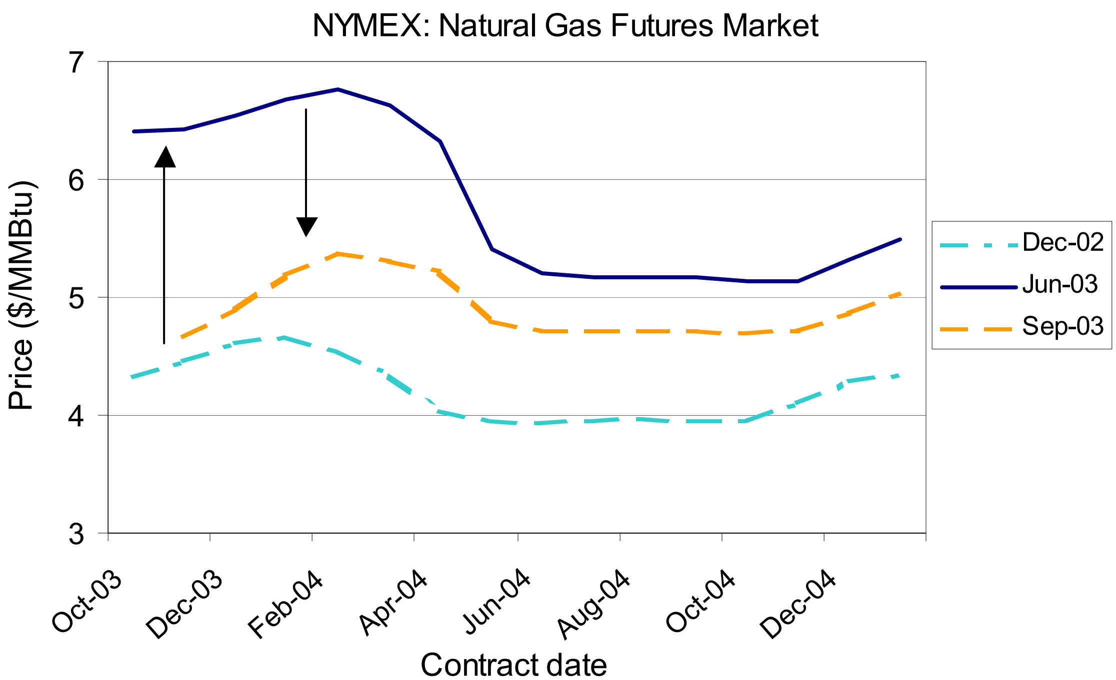

Figure 6.3: Natural Gas Futures Market
Source: The Wall Street Journal

Long-Term Natural Gas Price Forecasts

The Northwest Power and Conservation Council (NPCC) in 2003 released its *Draft Fuel Price Forecasts for the Fifth Power Plan*. The draft report includes a review of historical Northwest natural gas consumption and prices, as well as a forecast of future natural gas consumption and prices through 2025. The report observed that regional consumption had grown rapidly over the last decade or more, with an average annual growth rate of 6.8 percent during the period from 1986 to 2000. Growth was particularly rapid in the industrial and electrical generation sectors. This growth coincided with a period of low or falling natural gas prices. Historically in the Northwest, natural gas powered electrical generation had a low capacity utilization factor, only being used for peaking plant operation, or full time only on an emergency basis when hydroelectric generation was insufficient due to low rainfall or snowpack. This pattern began to change in the late 1990s as gas-fired generation that was intended to operate at a high capacity factor was either proposed or put into service. Since 2000, 3480 MW of gas-fired electrical generating capacity has been installed in the Northwest, 1390 MW of this in Washington. An additional 8,100 MW is planned, permitted or under construction for the region, and 2,120 MW for Washington State[15].

The bulk of the new gas-fired electricity generation is expected to require firm natural gas supplies and pipeline service. Because of its low capacity utilization factor, earlier gas-fired generation typically used interruptible supply and pipeline service, which aided in

[15] Much of the 7,900 planned or permitted gas-fired generation projects in the region have been suspended and are not likely to be developed.

meeting peak day demand requirements for the region. In addition, the new gas-fired generation units will be running at maximum capacity during the winter months when demand in the commercial and residential sectors is highest, thereby putting added strain on the gas transportation infrastructure. As the gas usage pattern for electricity changes, other strategies, such as increased pipeline capacity, gas storage and LNG peak shaving facilities will become necessary.

The NPCC predicts that supplies from the WSCB in Canada and the Rockies region will be sufficient over the next 20 or so years. The NPCC used its own forecasting model and developed low to high range price forecasts for natural gas out to 2025. These results are summarized in Table 6.1 below.

Table 6.1: NPCC forecast of U.S. wellhead natural gas prices (2000 $/MMBtu)

Year	Low	Medium	High
2000	3.60	3.60	3.60
2003	4.00	5.00	5.80
2005	2.50	3.25	4.25
2010	2.40	3.25	3.70
2015	2.55	3.40	3.70
2020	2.60	3.50	4.00
2025	2.65	3.60	4.25
Demand growth rate	*0.29*	*0.51*	*0.00*

The NPCC noted that because of the diminished amount of excess productive capacity in the natural gas industry, price volatility should be expected, and that price excursion above and below the forecast price trends shown above should be expected. Factors influencing price volatility included, but are not limited to, unseasonable weather, and high or low levels of economic growth.

The NPCC regional price forecasts are compared with the national prices forecast by the National Petroleum Council (NPC), the Energy Information Administration (EIA), and the California Energy Council (CEC) in Table 6.2 below.

Table 6.2: Summary of price forecasts ($/MMBtu)

Forecast year	NPCC (2003)	NPC 1999 & 2003	EIA 2001 & 2004	CEC (2003)
Base year price (yr)	3.60 (2000)	2.00 (1998) 5.00	3.60 (2000) 2.95 (2002)	2.95 (2002)
2005	3.25	2.50 4.50	2.66 ---	3.15
2010	3.25	3.00 4.25	2.85 3.40	3.40
2015	3.40	3.50 4.25	3.07 4.19	3.79
2020	3.50	---	3.26 4.28	---

The more recent price forecasts are for the most part reasonable, and indicate that the average natural gas wellhead price will be approximately $4/MMBtu (expressed in 2000 dollars) by 2015. Over the next couple of years gas prices may be slightly higher than the forecast 2005 values shown above. By the 2010 to 2015 time period significant quantities of LNG and Arctic gas should be entering the market, which will dampen upward price pressure and volatility.[16]

Summary

Since 2000, natural gas prices have been significantly higher and more volatile than they were during the 1990s. The key factors leading to high and volatile prices, mitigating factors, and the short-term and long-term prices forecasts are summarized below.

1. Recent high prices and volatility are primarily caused by gas supply limitations. The move to short-term contracts and the spot market tend to exacerbate price volatility.
2. Prior to 1997 there was sufficient excess gas production capacity to limit price increases and volatility. By 2000 a supply-limited market had developed and remains with us today.
3. Price and volatility are affected by weather, storage levels, storage withdrawal rates, oil prices, inelasticity of supply and demand, pipeline constraints, and the lack of timely and reliable information.
4. Factors that can mitigate high prices and volatility are sufficient storage, fuel switching capability, excess productive capacity, long-term contracts, and more timely and reliable information.
5. Higher gas prices have resulted in demand destruction and fuel switching primarily in the industrial sector, as well as short-term conservation and efficiency efforts.
6. The Industrial Energy Consumers of America estimate the direct cost of recent high gas prices at $111 billion over 41 months. The inclusion of indirect costs would add significantly to this cost number.
7. The EIA forecasts continued high but easing natural gas prices during 2004 and 2005. However, the futures markets forecast prices in the range of $5 to $6/MMBtu for the next two years.
8. The EIA and the NPC forecast prices in the low $4/MMBtu range (2000 dollars) for the year 2015. When significant new gas resources, such as LNG imports and Arctic gas, are developed upward price pressure and price volatility will be moderated.

The higher natural gas prices that are anticipated for the near- to mid-term will have a pronounced impact on gas demand growth through 2010. High gas prices will make the payback for efficiency and conservation efforts by residential, commercial and industrial consumers appear even more attractive. The industrial sector will continue to experience demand destruction as energy intensive businesses relocate to parts of the world with less expensive energy resources. In the electrical generation sector, high gas prices will stimulate interest in efficiency programs, and coal-fired and renewable electricity generation.

---

[16] The NPC and the EIA evaluated a scenario where development of LNG imports and Arctic gas were limited for political and financial reasons. The resulting long-term market price for natural gas in this scenario was substantially higher.